4 Transmission Planning Criteria, AC Integration Studies, and NERC Standards

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The ac system integration studies made available by Nalcor to MHI for review were conducted for the Gull Island Generating Station and the 3-terminal 1600 MW HVdc interconnector, with one termination at Soldiers Pond and another termination at Salisbury, New Brunswick (Exhibits CE-01 through CE-09). The project definition changed, in November 2010 following completion of the Nalcor project alternatives screening study (DG2) with Nalcor's decision to proceed with generation at Muskrat Falls using a point-to-point HVdc transmission system (Labrador-Island Link) with the inverter station at Soldiers Pond. There was insufficient information provided to form an opinion on the suitability of the ac system integration studies for the project, as redefined. However, MHI was able to examine the planning criteria in use at Nalcor and previous integration studies for Gull Island which noted some relevant ac transmission system issues.

4.1 Transmission Planning Criteria

The Planning Criteria is a policy document that will clearly identify the limits that trigger when new facilities need to be built, or when existing facilities need to be upgraded.

Planning criteria can be very prescriptive; however, as outside stakeholders can influence their application, the ideal document will have sufficient policy detail to direct staff and point to supporting external documents[102]. The application of Planning Criteria can also be influenced by corporate decisions or regulatory requirements. As an example, a utility may join a regional reliability group or sign an interconnection agreement that contractually obligates the parties to adhere to certain planning criteria.

Nalcor provided a document that describes the NLH and Nalcor power system planning criteria[103]. In this submission Nalcor not only provided the criteria, but also a self-assessment of their compliance. The criterion that was submitted is at a very high level and does not deal with the specifics. In some respects this is an ideal format as the corporate policies, guidelines, and standards that are required to adhere to the planning standards may have multiple stakeholders and are subject to change.

Exhibit 42 is an example of a document that supports the Planning Criteria. As an example, the Planning Criteria speaks to maintaining power flows at or below normal ratings for the equipment. How that criterion is accomplished for transmission lines is explained clearly in 3.2 of Exhibit 42[103]. This section identifies that there are three ratings: winter, summer/fall, and summer; and explains how they are developed. Of interest in this discussion is that the practice of defining three different ambient

[102] To inform stakeholders, many entities publish their Planning Criteria and supporting documentation on their external websites.
[103] Exhibit 42, Nalcor, "NLH 2009 Planning Criteria Review", 2009

temperatures is not an industry standard. However with the background provided in this document it is the appropriate practice in this situation.

Exhibit 42 refers to a second document titled "Bulk Power Systems Planning and Operations Criteria for Newfoundland and Labrador Hydro" which was developed by Power Technologies Incorporated in 1983. Exhibit 42 states that this document "has been considered to provide the framework for Hydro's planning criteria and adoption of all criteria as the long term objective". This is another document that needs to be referenced by the Planning Criteria as it will assist the person using the criteria understand how it is applied.

Ideally, planning criteria needs to be a high level document that directs the reader to supporting documentation or standards which identifies how the criteria will be met. Although some entities may not have published these documents, they will be the first to be examined following a major event, such as a black out that draws public attention. Therefore, many entities are now publishing some or all of these documents on their website.[104]

With the advent of open access interconnection tariffs, many entities have adopted the development of interconnection requirements to help third parties meet their planning requirements. For example, Manitoba Hydro publishes the "Manitoba Hydro Interconnection Requirements" report, which defines the conditions and requirements that an independent party must meet to obtain its *letter of commercial operation*[105]. The first page states that "Compliance with the technical requirements described in this document will ensure that facilities interconnected to the Manitoba Hydro Transmission System will comply with the planning criteria of Manitoba Hydro." This document includes sections on:

- System Information and Design Practice
- Generation Interconnection Requirements
- Wind Generator Interconnection Requirements
- Customer Load Interconnection Requirements
- Transmission Line Owner Interconnection Requirements

The third revision of this document is publically available on Manitoba Hydro's Open Access Same Time Information System page.

The format used by Nalcor could be improved by making references to its external and internal standards, guidelines, and policies; there is an example of this in Nalcor's Transmission Planning Criteria. The distribution planning criteria for normal voltage makes reference to the CSA CAN3-C235-83 Standard and the CEA "Distribution Planner's Guide". The guide clearly states how Nalcor intends to apply these criteria while keeping the Distribution Planning Criteria at a high level. Applying this practice to the remainder of the planning criteria would be beneficial.

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[104] For example Con Ed (NY) , AESO (AL) , CLECO (LA), and Eirgrid (Ireland)
[105] A letter of commercial operation is a document issued by a Tariff Administrator indicating agreement that compliance to all interconnection requirements are met under the applicable signed Interconnection Operating Agreement.

4.2 AC Integration Studies

Nalcor filed the following documents to describe the transmission assets required to support to the interconnections to Labrador and the Maritimes:

- Exhibit 23: Historical Summary of the Labrador-Island HVdc System Configuration for the Lower Churchill Project (1974-Present) – July 2011
- Exhibit CE31 Rev 1: Gull Island to Soldiers Pond HVdc Interconnection dc System Studies – December 1998
- Exhibit CE03/CE04: Lower Churchill Project DC1020 HVdc System Integration Study Volumes 1 and 2 – May 2008
- Exhibit CE10: Lower Churchill Project DC1210 HVdc Sensitivity Studies – July 2010

With the redefined project definition, these studies do not adequately describe the facilities required to successfully operate the transmission system under the new configuration. As such, there may be unidentified risks in proceeding with this project at this time. For example, the ac integration studies could identify requirements for additional back-up generation, new transmission lines, enhanced protection schemes or other system additions to maintain operation of the system at an acceptable level of performance. Such additions could add costs to the Infeed Option.

The response to RFI PUB-Nalcor-143 indicated that the ac integration studies for the current configuration would be completed by November 2011, which has now been delayed to the end of March 2012[106]. System integration studies completed as part of the project alternatives screening process, and provided to MHI by Nalcor, were for a Gull Island development with a 1600 MW three terminal HVdc system to Newfoundland and New Brunswick. Significant changes were made to the overall project definition with the proposed Muskrat Falls Generating Station development, and the deletion of the New Brunswick link. Good utility practice requires that these integration studies be completed as part of the project screening process (DG2); MHI considers this a major gap in Nalcor's work to date. These integrations studies must be completed prior to project sanction (DG3).

In the response to RFI MHI-Nalcor-39, Nalcor did supply a study plan which described the scope of work for the various ac integration studies[107]. It should be noted that this study plan does include the operation of the Maritime Link and contains: modes of operation, criteria, and a number of contingencies to test the performance of the integrated system. For example, a three-phase fault or slow clearing single-phase-to-ground fault close to the converter station could cause a temporary block of the Labrador-Island Link, which would impact the Newfoundland power system. Depending on the type of control systems employed in the Labrador-Island Link HVdc Link and the Maritime Link, remote faults off the Island of Newfoundland could cause oscillations on the Island of Newfoundland.

One would expect that there is a predefined set of disturbances in the Maritimes for all interconnection studies. If there is any possibility that the dynamic response from such disturbances

[106] Response to RFI PUB-Nalcor-143
[107] Response to RFI MHI-Nalcor-39

will be transferred into the study area, complete ac integration engineering studies should include a set of representative disturbances from outside the study area.

Although the studies filed to date cannot be used to validate the adequacy of the facilities required for these new interconnections, they did provide some insights on the dynamic issues of the island power system. Exhibit CE-03, filed by Nalcor in support of this project, included a number of recommendations:

- The effectiveness of power system stabilizers in the Newfoundland system should be investigated. This includes a review of the design and tuning of existing stabilizers and identification of potential new stabilizers that can benefit the overall small signal stability of the system.
- HVdc run-up and run-back schemes should be implemented to improve overall system stability. [108]

It is noteworthy that in the response to RFI MHI-Nalcor-39, the study scope supplied by Nalcor identified that in the event of a loss of the entire Labrador-Island Link HVdc link, the consultant was to assess the requirements for a special protection scheme for load shedding. Such a load shedding scheme could involve tripping "the Avalon, and potentially the Burin Peninsula depending upon system load conditions and HVdc Link load conditions"[109].

The documentation submitted to date has made reference to a 200% overload on the HVdc system for 10 minutes and a continuous overload capability of 150%. A 200% overload capability is a very good feature; however, it would require very dependable and fast-acting mitigation schemes, since the overload is only allowed for 10 minutes. As a 10 minute window for mitigating overloads is short, proposed mitigation processes should identify how the overload will be mitigated to the continuous overload capability of 150%. If the mitigation scheme depends on a third party, the third party should confirm that it is reasonable to assume that its mitigation plan can be put in place, even if details of the plans are in the formative stage. It should be noted that if an overload of more than 150% cannot be mitigated in 10 minutes, then load must be shed. In 2001, XCEL Energy developed a set of procedures called Fast Actions for Secure Transmission. In these procedures it agreed to run-back the Sherburne County Generating Station based on an event from a select list of area contingencies. Once reserves and congestion management processes could be enacted, the schedule at the station would be restored. The reason for implementing this procedure was in recognition of the fact that traditional mitigation schemes were not fast-acting enough to provide the relief needed.

Mitigating an overload below the continuous overload rating does not need this level of detail as the options available to the system control operators are greater. The continuous overload capability of 150% will be helpful in mitigating a significant number of contingencies that involve the loss of ac generation or dc system contingencies.

[108] Exhibit CE-03 (Public) "Lower Churchill Project DC1020 HVdc System Integration Study - Volume 1", May 2008
[109] Response to RFI PUB-Nalcor-31

4.3 NERC Standards

"Good Utility Practice" is a policy that most utilities recognize, either voluntarily or by regulation. The principle behind good utility practice is that electric utilities will adopt the practices and methods of a significant portion of utilities within a geographic boundary. For example, in Newfoundland and Labrador, good utility practice is defined in the Water Management Regulations, N.L.R. 4/09, s. 2(d) under the Electrical Power Control Act, 1994, S.N.L. 1994, c. E-5.1, s. 4. This regulation states that:

> *"'good utility practice' means those practices, methods or acts, including but not limited to the practices, methods or acts engaged in or approved by a significant portion of the electric utility industry in Canada, that at a particular time, in the exercise of reasonable judgment, and in light of the facts known at the time a decision is made, would be expected to accomplish the desired result in a manner which is consistent with laws and regulations and with due consideration for reliability, safety, environmental protection, and economic and efficient operations."*

This definition is substantially the same definition for all North American utilities that recognize and adhere to "good utility practice".

Since the August 14, 2003 blackout, most jurisdictions in North America, including at least eight provincial jurisdictions in Canada, have adopted the NERC standards as their reliability standards. In the US, this was accomplished through regulation. Following the release of the final report of the August 14, 2003 blackout in the United States and Canada, the US Federal Energy Regulatory Commission issued a Policy Statement[110] as follows: "In this Policy Statement, we clarify that the Commission interprets the term "good utility practice" to include compliance with NERC reliability standards or more stringent regional reliability council standards". In Canada, John Efford, Minister of Natural Resources, wrote a letter[111] with his US counterpart to the President of the United States and the Prime Minister of Canada. In it he states that, "The report makes clear that this blackout could have been prevented and that immediate actions must be taken in both the United States and Canada to ensure that our electric system is more reliable. First and foremost, compliance with reliability rules must be made mandatory with substantial penalties for non-compliance." In September 2006, the National Energy Board (NEB) recognized NERC as the Electric Reliability Organization[112]. In the News Release announcing this action, NEB Chairman Kenneth Vollman stated that, "We've been long-time supporters of mandatory reliability standards for international power lines and by recognizing NERC as the single ERO in North America; we've taken an important step towards strengthening that goal." This common action in the USA and Canada allows NERC's reliability standards to meet the requirement of being a practice that is consistent with the methods or acts engaged in or approved by a significant portion of the electric utility industry, even if the scope of those methods or acts is limited to Canada.

In Canada, eight of the ten jurisdictions have accepted NERC standards as their reliability standards. It may be understood that these eight jurisdictions have adopted mandatory standards with penalties solely because of interconnections with the USA. However, Alberta has no interconnections with the

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[110] FERC Docket PL04-5-000 before Commissioners Pat Wood, III, Chairman, Nora Mead Brownell, Joseph T. Kelliher, and Suedeen G. Kelly "Policy Statement on Matters Related to the Bulk Power System Reliability"," April 2004
[111] U.S.-Canada Power System Outage Task Force, "August 14th Blackout: Causes and Recommendations,"March 2004
[112] National Energy Board, " News Release 06/23", September 2006

USA, Quebec is dynamically isolated from the eastern interconnection, and Saskatchewan is virtually isolated from the USA through a single tie with phase shifter control, these jurisdictions had their own reasons for subjecting their utility's provincial operations to NERC standards with penalties for non-compliance.

The Nova Scotia Utilities and Review Board issued an order on the application by North American Electric Reliability Corporation on July 20, 2011. This order adopts and puts in force NERC Standards for Nova Scotia Power Inc. where the Standards and Criteria are mandatory and enforceable for users, owners and operators of the bulk power system in Nova Scotia. Thus the NERC reliability standards and NPCC regional reliability criteria are mandatory in Nova Scotia.

As Alberta has no ties to the US, one may consider it similar to Newfoundland and Labrador in power system operations. The Alberta Electric System Operator has adopted the mandatory use of NERC standards for use within Alberta. As a number of reliability standards have no application in Alberta due to its isolation from the USA, they have decided not to enforce all the NERC standards. Presently there are 43 non-applicable standards listed on their website[113].

With near unanimous acceptance of mandatory standards with penalties within Canada aimed at increasing the reliability of the provincial networks within Canada, it is hard to justify that NERC standards are not a practice, method or act approved by a significant portion of the electric utility industry in Canada. Therefore any utility that is assessing their adherence to "Good Utility Practice" must consider their adherence to NERC Standards.

NERC grades system operations into four categories with Category A being all facilities in service with no disturbance, to Category D which is an extreme event with two or more elements removed or elements cascading out of service. The allowable mitigations to a Category D contingency does allow for angular instability. Listing the operating condition and contingency as Category D does not allow the transmission owner to disregard the disturbance. NERC requires that Category D contingencies be assessed annually and be acceptable to the associated Regional Reliability Organization[114]. NERC also requires that Category D scenarios be studied from years one through five, with all firm transfers modeled, and all existing and planned facilities included.

NERC transmission planning standards list a 3 phase fault as a Category B contingency.[115] A category B contingency must maintain a stable system where both the thermal and voltage limits are within applicable ratings. The loss of demand, curtailing of firm transfers, or cascading outages are not acceptable outcomes for this contingency. Nalcor has stated that it does not plan to address a 3 phase fault at Bay d'Espoir as the present system fails to maintain angular stability following this contingency under some operating conditions[116]. As the system response to this disturbance falls outside of the requirements for NERC Standards and therefore outside of the definition of "Good Utility Practice", Nalcor's response to this situation is not aligned with utility best practice.

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[113] http://www.aeso.ca/
[114] TPL-004-1, "System Performance Following Extreme BES Event – Version 1", February2011
[115] TPL-002-0b, "– System Performance Following Loss of the Single BES Element-Version 0b – Approved", November 2009
[116] Response to RFI MHI-Nalcor-83

Nalcor could decide to place three phase faults into Category D, instead of NERC's classification as a Category B disturbance; there would be obvious financial benefits to this decision. A Category B disturbance has a performance specification that would have to be met while a Category D disturbance would only be presented to demonstrate what would happen if the disturbance were to occur. However neither category can be ignored and must be studied. Even if the system is allowed to become unstable following a three phase fault, it is important that the magnitude of the instability be demonstrated. Are the effects of the disturbance only local to the disturbance or do they have wide ranging impacts? For example, for a three phase fault at Bay d'Espoir, angular instability will occur under some operating conditions. If out of step relays employed to detect that angular instability and cause an orderly separation, will the addition of new facilities impact the ability of the out of step relays to perform their function? Electing to not consider the impact of disturbances in studies, even if the disturbance does not require an investment to mitigate, is never a good practice.

Nalcor has stated that the Emera Maritime Link will be built and operated in compliance with the applicable NERC standards. However, for Newfoundland

> *"the Government of Newfoundland and Labrador has not established a role for NERC within the province. As a result, the interconnection of the Maritime Link to the Island Interconnected System and the facilities of Newfoundland and Labrador Hydro will be approved by Hydro. Hydro's reliability, design, and operational criteria will apply to the Newfoundland side of the interconnection."*[117]

As a result Nalcor currently does not comply with NERC standards. [118,119] A majority of utilities in Canada have adopted the definition of "good utility practice" that incorporates adherence to NERC standards. Also, should the Maritime Link proceed, and Nalcor participates in the electricity marketplace, it is MHI's opinion that NERC standards will ultimately apply. It would be prudent for Nalcor to complete a self-assessment and prepare for compliance to NERC standards as NERC standards will apply to the Labrador operations of the Lower Churchill Project.

4.4 Conclusions and Key Findings

Nalcor provided a number of documents in the areas of transmission planning criteria, ac integration studies, and NERC standards as they relate to good utility practice, which were reviewed by MHI.

The transmission planning criteria provided by Nalcor for review is a key document that clearly identifies the operating limits that trigger when new transmission facilities are required, or when existing facilities need to be upgraded when violated. MHI reviewed the transmission planning criteria and found this document appropriate.

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[117] Response to RFI PUB-Nalcor-140
[118] Exhibit 106, Nalcor, "Technical Note: Labrador –Island HVdc Link and Island Interconnected System Reliability", October 2011
[119] Response to RFI PUB-Nalcor-164

The final ac integration studies for the Labrador-Island Link HVdc system were not available for review. As a result, the following key finding is noted:

- System integration studies completed as part of the project alternatives screening process, and provided to MHI by Nalcor were for a Gull Island development with a 1600 MW three terminal HVdc system to Newfoundland and New Brunswick. Significant changes were made to the overall project definition with the proposed Muskrat Falls Generating Station development, and the deletion of the New Brunswick link. Integration studies that would support the changes have not been completed and Nalcor now advises that the studies will not be available until March 2012[120]. As the full requirements for integration of the Labrador-Island Link HVdc system are not known, there may be additional risk factors that may impact the cumulative present worth of the Infeed Option. For example, installation of backup supplies to cover operational limitations in the Labrador-Island Link HVdc system may be required, and additional transmission lines may be needed to maintain acceptable system performance. Spare equipment requirements also need to be taken into consideration. Good utility practice requires that these integration studies be completed as part of the project screening process (DG2). MHI considers this a major gap in Nalcor's work to date. These integrations studies must be completed prior to project sanction (DG3).

Through MHI's review of the documentation, and related RFIs noted in the report, the issue of NERC Standards was noted as a concern, particularly with new interconnections planned from the Island of Newfoundland to Labrador, and from the Island of Newfoundland to Nova Scotia. The key finding from the NERC Standards review is as follows:

- MHI finds that Nalcor currently does not comply with NERC standards. A majority of utilities in Canada have adopted the definition of "good utility practice" that incorporates adherence to NERC standards. Also, should the Maritime Link proceed, and Nalcor participates in the electricity marketplace, NERC standards will ultimately apply. MHI recommends that Nalcor complete a self-assessment and prepare for compliance to NERC standards with or without the Maritime Link.

[120] Response to RFI PUB-Nalcor-143